December 19, 1996

VIA FEDERAL EXPRESS
OVERNIGHT PRIORITY

Docket Office
California Public Utilities Commission
505 Van Ness Avenue, Room 2001
San Francisco, California 94102

Re: R.94-04-031/I.94-04-032

Dear Docket Clerk:

Enclosed for filing in the above-entitled matter are the original and five copies of the **COMMENTS OF THE CALIFORNIA ENERGY COMMISSION IN RESPONSE TO D.96-10-074**. Please return the extra copy in the enclosed, stamped, self-addressed envelope. Thank you for your attention to this matter.

Very truly yours,

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Enclosures

cc: Restructuring Service List

BEFORE THE CALIFORNIA PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking The Commission's Proposed Policies Governing Restructuring California's Electric Services Industry and Reforming Regulation	))))))	R.94-04-031 (Filed April 20, 1994)
Order Instituting Investigation on the Commission Proposed Policies Governing Restructuring California Electric Services Industry and Reforming Regulation	))))))	I.94-04-032 (Filed April 20, 1994)

COMMENTS OF THE CALIFORNIA ENERGY COMMISSION IN RESPONSE TO D.96-10-074

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I. Recommendations and Summary of Argument

In these Comments the California Energy Commission (CEC) responds to the opportunity to discuss issues regarding metering and billing for retail electric services, as requested by the California Public Utilities Commission (CPUC) in decision D.96-10-074.

These Comments are organized into five sections. This section sets forth the CEC's recommendations and summarizes the argument. Section II presents the rationale for the CEC's approach and offers a preliminary sketch of business activities and information flows in the restructured electric industry. Section III discusses the specific issues raised in D.96-10-074, along with several others the CEC believes are pertinent to policy decisions on metering and billing services. Section IV discusses the specific metering and billing strategies outlined in D.96-10-074. Section V describes the CEC's proposal that the CPUC adopt a comprehensive Retail Information Management Plan to guide the design and deployment of interval metering and data communication systems and the development of protocols for access to meter information by industry participants.

A. Recommendations

1. The CPUC should adopt a Retail Information Management Plan (RIM Plan) which describes: the information flow needs of participants in the restructured industry; the functions that metering and communication systems should support; the standards for hardware, software and content required of metering and data communication systems; the roles various industry participants will be required or permitted to play; and, the monitoring, oversight and flexibility needed to ensure implementation. Until such a plan is adopted, the CPUC should not proceed with any of the four metering strategies outlined in D.96-10-074.

2. The CPUC should direct an industry-wide stakeholder group to develop and submit a draft RIM Plan to the CPUC for review and adoption. [We note that the CPUC's December 9, 1996 Joint Assigned Commissioner Ruling (JACR) orders the IOUs to convene a meeting with participants of the Direct Access Working Group (DAWG) and others to assess the data and communication systems required for direct access. While the focus of the ruling is to inform a decision on phase-in of direct access, which is narrower than the CEC's proposal, the parties who come together for the purpose of the JACR would be an ideal group from which to designate a team to develop a draft RIM Plan.]

3. The CPUC should not authorize utilities to include in rate base or expense any costs associated with deploying end-use metering and data communication systems, unless these are compatible with the RIM Plan. The CPUC should rescind its earlier directions to utilities or utility distribution companies (UDCs) to deploy real-time-pricing (RTP) meters for certain customers on a specific schedule.

4. The CPUC should not open metering and data communication services to competitive supply until a comprehensive RIM Plan is adopted to guide the activities of various industry participants. There is, however, a valid argument for allowing alternative billing arrangements to support direct access competition in 1998.

5. The CPUC should order the integrated electric utilities to develop unbundling cost studies for four primary functions rather than three, where the four functions are a distribution "wireco" and a "business" entity in addition to generation and transmission. As long as utilities' business and customer service activities are either lumped into the distribution function or arbitrarily allocated across generation, transmission and distribution, the line between natural monopoly

and competitive market services will remain too fuzzy to allow a logical, systematic approach to D.96-10-074's important questions about unbundling, metering, billing, etc.

B. Summary of Argument

The purpose of this section is to summarize the rationale underlying the numerous points discussed in these Comments. Our primary goal is to convince the CPUC of the importance of reframing the major issues raised in D.96-10-074 along the lines suggested in these comments, and of the urgency of initiating development of a comprehensive plan to guide all subsequent decisions regarding metering, data communication and information management.

1. Functional Unbundling of the Integrated Utility Requires Four Fundamental Components.

The problem of allocating all the activities of the integrated electric utilities to the G, T and D functions cannot be resolved in a logically consistent way because, as Commissioner Duque noted in his May 8, 1996 Assigned Commissioner Ruling (ACR): "The vertically integrated utility undertakes many activities which have no unique relationship to any of the three functional areas." The solution to this problem is to reframe unbundling to encompass four primary functions: generation (G), transmission (T), distribution as a narrow "wireco" (D), and the electric service business (B). Four-fold unbundling offers a logical framework to guide the cost unbundling of the existing utilities, and represents the most sensible way to think about the mature, restructured industry. In particular, it allows the transition period and the mature marketplace to be brought together under a unifying conceptual framework. [See Sections II.A. and II.B.]

2. Direct Access Opens the Fourth Component to Competition.

The CPUC's "Preferred Policy Decision," D.95-12-063, conceives of industry restructuring primarily as three-fold unbundling (i.e., into G, T and D), where G becomes competitive while T and D remain regulated monopolies. Most restructuring policy, in the states and at the federal level, seems to be based on the same concept. That concept may have been appropriate a year ago, but there have been many new developments and much knowledge gained over the past year. The point that is missed by adhering to that concept now is that the decisions to require equal access to transmission systems and to allow direct access between end-use customers and generation providers has spawned a completely new marketplace populated by myriad intermediaries engaged in the business of buying and selling electricity.

Much of this activity was always implicit in the vertically-integrated utility, in the form of the "non-unique" activities identified by Commissioner Duque — management of operations, customer service and support, metering and billing and regulatory activities — plus a few more such as market research and customer retention strategies — all of which we refer to as the B component. Under competitive restructuring, this implicit B component of the utility is expanding as new types of intermediaries arise and develop new business ideas such as customized service contracts, financial instruments, multi-utility billing, value-added services, and much, much more. As a result, it no longer makes sense to think about electric industry restructuring in the narrow sense of opening the G sector to competition. Specifically, the decision to allow direct access has opened the retail franchise and set the stage for a competitive electricity business, in which G, T and D are the intermediate inputs to be obtained by retail and wholesale electric service providers. [See Section II.A.]

3. Information Flows are Key to the Success of the Restructured Industry.

Before restructuring all flows of essential information were internal to the integrated utility. In the restructured industry, these internal information flows become transfers of information among a great variety of parties, several of whom are essential to the reliable functioning of the electric system. Even ignoring the B component, the separation of G, T and D into distinct components creates new information needs to support activities that were never performed before: settlement of imbalances, separate load forecasting for direct access customers of each provider and full-service customers of the UDC, submission of balanced schedules to the independent system operator (ISO) by scheduling coordinators, and more. Adding the B component and assessing the information requirements for viable competition in the business arena, activities such as market research and direct marketing that utilities performed only in a limited way will now become full-scale competitive necessities. Finally, revenue cycle activities will be performed for all four components, as G, T, D and B must all be financially viable. Thus information flows are at the core of the restructured industry. [See Section II.C and D.]

4. Multi-Party Access to Data and Security of Information Flows Argue for a Central Entity to Perform Some Essential Information Management Activities.

D.96-10-074 emphasizes the CPUC's concerns about ensuring multi-party access to data and the integrity of information exchanges related to system operations and revenue cycle activities. The CEC shares these concerns and believes that the best way to address them is to create a central entity to manage certain "core" information activities. Included in this core would be the unique authority to obtain meter data for all customers regardless of service provider, to maintain a database of customer usage data, to disseminate specific packages of information in a timely fashion to various entities in accordance with established protocols, to enable access to certain kinds of information to authorized parties, and to maintain the security of the information management system.

The CEC recognizes that some parties will be alarmed at the idea of a central entity having exclusive control over these activities, and therefore recommends that the parties themselves design, create, own and operate this central entity for their mutual benefit, rather than conceive of it as a government agency or a regulated, private, for-profit monopoly. The VISA bank-card system offers an instructive example of how a stakeholder-owned, not-for-profit, information management entity can successfully serve the needs of large numbers of competing businesses while maintaining appropriate restrictions on information access. The stakeholder group that undertakes development of the RIM Plan should investigate the VISA system and assess this option for the electric industry. [See Section II.D, Section III.A, items 2 and 4, and Section V.]

5. Metering and Billing Decisions Must Support Overall Industry Restructuring, Not Just Direct Access.

D.96-10-074 frames the metering and billing issues before the CPUC in terms of support for direct access. The CEC believes this framing is too narrow. The metering and billing decisions the CPUC makes in the coming months will affect competitive services beyond direct access and customers other than direct access customers. Focusing narrowly on whether emergent Energy Services Providers (ESPs) may provide revenue cycle services for their customers ignores the needs of UDC bundled service customers, who will be the vast majority of customers and account for the bulk of energy consumed for the next few years at least. Moreover, decisions made too narrowly today may create new stranded assets in the future, as market opportunities evolve and private-sector initiatives shape the market's evolution in ways that transcend the narrow idea of a competitive generation market based on direct access. [See Sections II.C. and D.]

6. The CPUC Must Develop a Retail Information Management Plan (RIM Plan) to Ensure that New Metering, Data Communication and Information Management Arrangements Are Mutually Consistent and Serve the Needs of All Parties.

Based on the above, the CEC concludes that a comprehensive plan is essential as a basis for making optimal policy decisions about metering, data communication and information management for the restructured electric industry. The Plan we envision would describe: the information flow needs of participants in the industry; the functions that metering and communication systems should support; the standards for hardware, software and content required of metering and data communication systems; the roles various industry participants will be required or permitted to play; and, the monitoring, oversight and flexibility needed to ensure implementation. Some parties are pushing for quick decisions in these areas. The CEC believes, however, that it will be much more costly to adopt fragmented decisions driven by a sense of urgency than to develop a plan that addresses information issues in a comprehensive way. [See Section V.]

7. The CPUC Must Reassess D.95-12-063's Mandates for RTP Meter Installation.

D.95-12-063 directs utilities or UDCs to install RTP metering for all customers greater than 100 kW on a five year schedule, and requires UDCs to install a RTP meter for any customer desiring virtual direct access (i.e., UDC procurement of energy at hourly PX prices). Based on these requirements, the UDCs are asserting today that decisions on new metering and data communication systems have already been made by the CPUC. However, much has been learned since the Preferred Policy Decision was issued, and the metering requirements it imposes may no longer be optimal in light of new developments. The CPUC should therefore suspend implementation of D.95-12-

063's metering requirements until a comprehensive RIM Plan can be developed. [See Section III.B, item 3.]

8. The CPUC Must Determine How UDCs Will Handle PX Purchases for Full Service Customers and Identify the Information Flows Needed to Support this Function.

The August 30 DAWG Report discusses the critical roles for customer metering and data systems in making PX purchases by UDCs more efficient. However, the CPUC has not yet formally recognized this subject and has thus far provided no guidance about how UDCs should interact with the PX and the ISO to ensure least cost in serving the loads of full service customers. The issues to be addressed include: the procedures by which the UDC makes load bids to the PX, the cost penalties for inaccurate load bids, the metering and communication system needs to support UDC-PX and UDC-customer interactions, and the computation and recovery of imbalance and ancillary service costs. Utility rate applications filed on December 6, 1996, provide abundant evidence that no comprehensive thought has been put into these matters, and that no CPUC guidance directs utilities toward a common approach. [See Section V.B, items 1-3.]

9. Standards Are Needed to Ensure that Multiple Metering and Data Communication Technologies Fit Together Into a System that Provides Options for All Customers.

The CEC supports development of standards that permit multiple technologies to provide metering and data communication services. This position stems from an assessment of the requirements to support the CPUC's objective of "prompt availability of Direct Access to all customers" in a least cost manner. All customers must be connected electronically, and no single technology provides the long-term least cost means to accomplish this. In addition, standards must address more than the technological issues of interfacing various kinds of hardware and their data protocols; they must also specify the nature of the information that must flow between suppliers and customers. In effect, what is needed is a set of information-based performance standards combined with inter-operability standards for two key steps in the data communication flow: the link between customer meter and communication system, and the link between communication system and the central database. [See Section V.B, item 3.]

10. Competitive Supply of Unbundled Information-Related Services Should be Permitted Only When It is Demonstrated to Be Compatible With a RIM Plan.

The foregoing recommendations and arguments demonstrate the need for a comprehensive approach to the information flow needs of the restructured industry. Until a comprehensive approach is undertaken, it would be premature to open essential information-related services to competitive supply, for it could have significant negative impacts on overall efficiency and system reliability. The CEC unequivocally supports eventual competitive supply of unbundled services wherever appropriate, but only after the comprehensive Retail Information Management Plan has been developed and adequate specifications exist to ensure that the suppliers of these services and their practices are compatible with that Plan. [See Section V.C.]

II. Business Activities and Information Flows in the Restructured Industry

Section II.A develops the argument for a four-fold concept of the de-integrated electric utility and the restructured electric industry, including a business component (B) and a distribution "wireco" (D) as well as the more familiar generation (G) and transmission (T) components. Section II.B then provides a preliminary sketch of the activities comprising the B component and the counterparts of those activities that must be performed by financially viable G, T and D entities. Section II.C derives some policy implications from the previous sections. Finally, section II.D provides a first effort at describing a comprehensive view of information flow needs in the restructured industry.

A. Unbundling the Business Component and the Distribution "Wireco"

1. The Problem.

D.96-10-074 reminds parties of Commissioner Duque's observation that revenue cycle costs "do not fit neatly into any of the broader unbundling categories." The Decision goes on to chide parties for taking the approach that revenue cycle and other activities such as management, customer service and regulatory activities belong to the distribution function and, therefore, that separate identification of the costs of these activities requires the unbundling of distribution costs. The CPUC expresses its concern in D.96-10-74 that this approach "may have skewed the debate," clarifies that it is "not ordering any unbundling of the distribution system . . ." and directs parties to respond to to Commissioner Duque's original request, namely, to "consider the most appropriate way to allocate these costs across the three functional areas."

In response to this problem, the CEC submits that trying to allocate all the costs in question across generation, transmission and distribution is problematic from the outset, and that any proposed solution will necessarily involve copious arbitrariness and will likely bear little relation to the operation of the competitive electric service market. In asserting this position, we point out that Commissioner Duque's observation in the May 8, 1996 ACR — that many activities of the vertically integrated utility "have no unique relationship to any of the three functional areas" — is more significant than has been realized thus far. Specifically, the problem with trying to allocate these "non-unique" costs across the three functional areas stems from a fundamental flaw in the three-fold unbundling model which has thus far provided the conceptual basis for restructuring policy. Fortunately there is a relatively simple fix.

2. The Solution: Four-Fold Functional Unbundling.

The CEC proposes that functional unbundling of utility service be conceived of as four-fold, not three-fold. The fourth component, which in addition to G, T and D has always been implicit in the integrated electric utility, is the business component, which we denote by B. For the problem of unbundling the existing industry structure, G, T, D and B should be thought of as four profit centers within the integrated utility. In the mature market, B would be the intermediary sector, which makes contracts to provide electric service to customers, both wholesale and retail, and obtains G, T and D services to fulfill those contracts.

In the integrated utility B includes everything that does not belong to one of the three physical components of electric service, G, T and D, with each of these configured as a financially viable entity. The D component in this model should be no more than a distribution "wireco" that connects end-users and delivers electricity to them from the transmission grid. Thus B would include customer service and support, revenue cycle activities, regulatory activities, market research, product development, customer retention, management of customer data bases, etc. To simplify the unbundling problem for the transition period, B might be conceived of and costed as the residual firm that remains after G, T and D have been de-integrated from the integrated electric utility.

A compelling advantage of the four-fold model is that it provides a consistent way to envision both the transition period and the mature market. In the mature market, B should be thought of as consisting primarily of the activity of selling electric service to customers, which will be performed by such entities as retail energy service providers (ESPs) and aggregators, power marketers and brokers, the PX, and UDCs. [The UDC would essentially be a combined ESP and distribution wireco, with the additional requirements of buying from the PX and providing default energy procurement.] B activities would cover all business activities normally associated with a retail or wholesale intermediary, including marketing, customer service, revenue cycle activities, customer information management, and procurement of intermediate goods and services, most notably, G, T and D.

In summary, the four-fold model offers a consistent, logical framework for developing public policy to address transition issues such as unbundling and costing of the "non-unique" activities that have been implicit in the integrated electric utility. In addition, the model lends itself naturally to a consistent view of the mature market. A quick survey of the new firms and new business activities arising in response to industry restructuring should make it clear that the market is evolving toward a vibrant, competitive business sector in which many different types of firms contract directly with customers to provide electric service and must then obtain the basic inputs required to deliver that service. The CEC believes that the four-fold model is a more realistic way to think about and develop policy for electric industry restructuring, for it recognizes private-sector business developments that are already underway.

Should any doubt remain about opening the B component of the integrated utility to competition, we point out that the CPUC's decision to allow direct access does just that. After D.95-12-063 and AB 1980 it is no longer possible to think in terms of making only the G component competitive. The CPUC has, in fact, opened the business of electric service to competition and invited new intermediaries to enter the market. A major failing of the conventional three-fold model, which recognizes only the G, T and D components, is that it does not recognize this fact.

B. Business Activities in the Four-Component Electric Industry

Table 1 lists some of the business activities performed by the B component and the three physical components (G, T and D) of the restructured industry. A few explanatory notes will help orient the reader to the table.

First, as a convenient shorthand, the term ESP will be used broadly in this table to refer to any entity active in the B area, whether wholesale or retail. For example, wholesale power marketers are included as ESPs for the sake of this discussion.

Second, G, T and D are defined narrowly to refer to the physical components of electric service. Thus G will refer narrowly to generation plants, which contract to produce electric energy and deliver it to the transmission grid, while D will refer narrowly to the distribution wireco that takes electric energy from the transmission grid and delivers it to end-use customers. These entities engage in certain business activities only to the extent necessary for them to be financially viable providers of the physical elements of electric service.

Third, the four columns represent functions, not the entities that perform the functions. The reason for this distinction is that a single entity may perform more than one function, whereas the emphasis of the four-fold model is to distinguish among the fundamental functions. For example, a utility distribution company (UDC) would be a combined D and ESP, with some qualifications such as the requirement to buy PX energy and the default-provider function.

Finally, the rows are the activities encompassed by the B component, broken down into three major categories: marketing, customer service and revenue cycle. To some extent, the physical components G, T and D will perform counterparts to these activities by virtue of the requirement that all functions must be financially viable. The entries under the G, T and D columns therefore identify business activities in which these entities will engage in the restructured environment.

Table 1. Electric Service Business Activities in the Restructured Industry

Business Function Activities (B: ESPs)	Generation Function Activities (G)	Transmission Function Activities (T: ISO)	Distribution Function Activities (D)
1. Marketing			

direct access G and ancillary services wholesale G and ancillary services virtual direct access (UDCs) market research value-added services & customized contracts multiple utility services combined efficiency & energy services	generators sell bulk energy and ancillary services by bidding into the PX and/or through bilateral contracts	by virtue of reliability responsibility, the ISO may create markets for ancillary services or purchase them directly	NA
2. Retail Customer Service			
general inquiries / first point of contact — primary role for ESP	NA	NA	NA (except by mistaken association with former IOU during transition)
starting/stopping accounts — ESP makes contract with customer, then conveys order to D for turn-on/off and new connection if needed.	NA	T is invisible to most end-use customers, but high voltage ones may have some T-service issues analogous to distribution issues	install hookups for new construction and major remodeling turn-on/off in response to ESP orders, or in case of customer default, per consumer protection regs
interruptions — initial call may come to ESP, who then informs D	NA	NA	restoring D-related service interruptions
provision of customer energy and billing records.	NA	NA	NA
3. Revenue Cycle			
metering — customer usage required for correct billing, whether direct access or default service	G measures energy and other parameters as delivered to the grid	ISO measures loads and injections at all nodes for assessing T charges	D measures out-take nodes and customer loads for assessing D charges
communication of usage data to database & RT prices to customers	NA	NA	NA
database management — by ESPs for retail customers	as required to support revenue cycle needs	as required to support revenue cycle needs	as required to support revenue cycle needs
billing — ESPs bill customers	G bills PX or ESPs	ISO bills ESPs	D bills ESPs
revenue handling	as required	as required	as required

C. Policy Implications

At least four implications for public policy may be drawn from the four-fold structure of the electric industry.

First, as noted above, the most useful cost unbundling exercise for the utilities to perform at this time would be to determine the costs of the three physical components of electricity supply as such, i.e., without arbitrarily allocating business and other non-unique activities to the physical components. In particular, utilities should develop cost studies for the distribution "wireco." Of course, because G, T and D entities must be financially viable, they will have to engage in business activities to some extent, and such needed activities should remain with those functions. Apart from those portions directly assignable to G, T and D, policy makers need to understand the costs associated with the business of electricity supply, which encompasses the direct link with customers, including revenue cycle activities, and for which G, T and D are necessary inputs.

Second, because B will encompass the arena of contracts with customers, policy makers must ensure that retail revenue cycle activities are allowed to evolve so as to serve the needs of all players in this competitive arena. It would be inconsistent with the present course of restructuring to give proprietary rights to these activities to UDCs or any other narrow group of parties.

Third, and closely related to the previous point, the CPUC should not view metering and billing questions too narrowly, i.e., only with the objective of facilitating direct access as suggested in the decision. Metering and billing issues extend beyond direct access in two directions: to a broader group of services, and to a broader group of customers. For example, customers who choose to continue receiving full UDC electric service may choose a virtual direct access option, may obtain value-added services from other providers, or may wish to have combined billing for electricity, gas, water, telephone, cable and home security. Policy decisions regarding metering and billing must be cognizant of the fact that technological and business developments in these areas will not be confined to a single type of service and the customers who choose to purchase that service.

The CPUC's notion that direct access availability and the provision of unbundled metering and billing services are two separable objectives [D.96-10-074, p. 12] is based on the three-fold model, in which all activities of the integrated utility must belong to G, T or D. In contrast, the four-fold model implies that direct access availability and metering and billing services are all encompassed in the B component. And since the direct access provision of D.95-12-063 has opened B to competition, it is no longer correct to think of metering and billing as "belonging" to G, T and/or D. The overarching issue for policy makers is the viability of a competitive electric service business sector.

Fourth, and most important, the four-fold industry structure must provide essential information management functions that were implicit in the integrated utility. The CPUC should address information management issues — including meter installation and reading, data communication, database management, data dissemination, information security, etc. — based on a comprehensive understanding of the information flow needs of the restructured industry. Some information flows will be driven by the operational requirements of the essential T and D monopolies. Others will be driven by revenue cycle activities of generators and business entities, and still others will derive from economic considerations of market efficiency. The CEC believes that a comprehensive map of essential and desired information flow should drive policy decisions regarding the elements of information management.

D. Information Flows in the Restructured Industry

As noted in the first recommendation (see Section I.A), a comprehensive RIM Plan must begin with an overview of the information flow needs of industry participants. This section discusses certain of those needs, with a focus on the customer usage data that will be obtained from customer meters.

1. Meter data will be required for more than direct access and revenue cycle activities.

In previous submissions to the CPUC (e.g., the August 26, 1996 Ratesetting Working Group Report and September 15 Comments on that Report), parties identified metering, data communication and customer database management as the first three of five revenue cycle activities, the last two being billing and revenue handling. These first three activities comprise what we call the "core information activities." While the core activities will indeed be crucial to the revenue cycle, they will also have other roles to play in the restructured industry. They will be needed for electricity system operations when all the components of that system are no longer under the central control of the integrated utility. They will also be needed for non-operational activities such as marketing, industry monitoring and oversight and public-interest research.[1]

Some of these other needs for customer meter data may seem obvious, but they have not yet been viewed systematically in discussions of the unbundling policy decisions now facing the CPUC. Table 2 presents a view of the core information activities and the other activities they support. The first section of the table describes the core activities. The second section looks at the specific needs of system operations, the third section looks at the revenue cycle, and the fourth section looks at marketing and other activities. The table assumes a restructured industry in which the operation of

[1] For more discussion on access to customer information by public interest and research entities, see Comments of the California Energy Commission in Response to the October 30, 1996 Direct Access Working Group Report on Consumer Protection and Education at 17-18.

the electric system involves multiple parties, each of whom must ensure the integrity of their own operations and their own financial viability. Together the categories of Table 2 encompass all the traditional revenue cycle activities of the integrated utilities as well as newly-decentralized or completely new system operations and competitive business activities.

One distinction that may not be obvious in Table 2 is that some of the activities require only one-way communication, i.e., from customer to the central facility, and require relatively infrequent transmission of data. The revenue cycle activities generally fit this model. Other activities require some enhanced functionality, usually in the form of two-way and/or high frequency of transmission. Examples are item 1.a, providing hourly price or load-drop signals to customers, and item 2.e, detection and location of outages and other operational problems. Clearly, as more parties contribute to the scoping of these information flow activities and as the industry evolves, there will be additional activities identified that do not have counterparts in either the existing integrated utility or the narrow direct access concept of restructuring.

A salient feature of Table 2 is the presence of several activities that did not exist under the integrated utility structure. A few examples are load bidding, settlement for imbalances, procurement of ancillary services and computing charges for transmission congestion. These activities as well as the familiar ones now require information flows among distinct parties, many of whom have competitive market incentives, instead of the fully internal information flows that characterized the integrated utility. The ultimate effect is that industry restructuring entails a complete restructuring of information flows, and hence the CEC's concern about basing metering and data communication decisions on a narrow objective of facilitating direct access or opening revenue cycle activities to competition.

2. Rate design decisions will determine whether T & D charges require consumption data.

The use of customer-specific energy usage data in the design of distribution tariffs is a threshold issue affecting the UDCs' need for such data for direct access customers. The CPUC must consider whether the UDC requires usage data for those customers for which it provides only distribution services, or whether the generation service supplier is the only entity requiring this data. Of course, the latter decision would not obviate the need for ESPs and UDCs to have metering and billing systems.

The question of using energy usage data to compute distribution charges will likely be addressed in the disposition of the rate applications that were filed by the utilities on December 6, 1996. However, it is not necessary to recover distribution system costs using rate designs for which energy consumption is the denominator. Moreover, since the great majority of distribution system costs are fixed, it would be inefficient to create distribution rates based on energy consumption.

3. Metering, data communication and access to the usage database support the entire industry.

This section has offered a preliminary description of how the core information activities — metering, data communication and management of a customer energy usage database — will be central to the efficient operation of the new industry structure. While some of the details of this description may be refined, this discussion demonstrates that the metering and data communication issues framed as direct access issues in D.96-10-074 should be reframed from a broader perspective that recognizes their crucial role for the success of the entire restructuring process. In the following sections, we utilize this broader perspective to provide comments on the specific questions raised in D.96-10-074. The CEC urges the CPUC to make its decisions on metering and associated activities in this broader context.

Table 2. Retail Information Management Activities in the Restructured Industry

ACTIVITY	DESCRIPTION OF ACTIVITY
1. Core Information Activities	
a. price and load drop signaling	(1) communicate hourly PX or 5-minute ISO prices to customers (2) provide signal to drop load from ISO to customers
b. interval metering	measure electricity consumption over a time interval (e.g., one hour)
c. consumption data uploading	transmit hourly consumption data to central consumption database
d. consumption database updates	verify readings and update database with new hourly data
e. data access and dissemination	(1) disseminate data to appropriate entities according to established protocols (2) enable access to database by authorized parties
f. information security	ensure security of information flows into and out of consumption database
2. System Operation Activities	
a. load forecasting	develop day-ahead and hour-ahead forecasts for contracted loads (UDC to PX and ESPs to scheduling coordinators)
b. load bidding	UDC and possibly ESPs make hourly bids to PX
b. generator scheduling	(1) PX develops matched generator schedule to match load bids (2) scheduling coordinators verify load/generation balances
c. ancillary services procurement	scheduling coordinators arrange for ancillary services to match loads and ISO arranges with ancillary service suppliers to provide services
d. imbalance identification	scheduling coordinators report actual loads at ISO-grid out-take points, and identify and/or allocate imbalances to specific customers
e. outage / problem detection	monitor system for outages and other problems, and quickly identify source and location
3. Revenue Cycle Activities	
a. energy imbalance settlement	on a daily basis, ISO matches 24 hourly energy imbalances with costs for imbalances, and submits bills to scheduling coordinators
b. ancillary service costing	ISO allocates ancillary service costs to scheduling coordinators
c. transmission congestion costs	transmission congestion costs are identified and assigned to specific generators and/or customers
d. energy consumption costing	total energy costs (generation and transmission congestion) are computed for each customer
e. billing	parties performing end-use customer bills utilize usage data and tariff or contractual formulas to compute costs and print bills for customers in accordance with supplier or CPUC approved protocols and formats
f. payment handling	customer payments are processed and posted as bank deposits

g. remittance processing	collect revenues from end-use customers and remit to appropriate suppliers and government agencies
h. auditing remittances	parties relying upon remittances from other parties periodically audit revenue stream finances and computations
4. Other Activities	
a. marketing	(1) perform market research to develop new products and services (2) target specific customers for direct marketing
b. regulatory requirements	(1) monitoring and oversight of the industry (2) assess achievement of policy objectives
c. public interest research	studies of consumer behavior, statewide energy situation, effectiveness of public policies and achievement of policy objectives, etc.

III. Discussion of Specific Issues Outlined in D.96-10-074

D.96-10-074 requests parties to comment on seven specific metering and billing issues which provide a basis for four metering strategies, on which parties are also requested to comment. Part A of this section addresses the seven specific issues. Part B then identifies several further issues which the CEC believes must be considered in determining the metering and billing strategies to be pursued. The four metering strategies of D.96-10-074 are addressed in Section IV.

A. Issues Identified by the CPUC

In D.96-10-074 the CPUC identified the following seven issues, the answers to which will influence its ultimate decisions on whether and how to unbundle metering and billing services:

1. Meter ownership;
2. Multiple provider access to data from a single meter;
3. Meter installation;
4. Competition in metering and billing;
5. Meter cost;

6. Bill consolidation and billing costs;
7. Standardization of communication protocols.

Before discussing each of these issues, the scope of activities encompassed by the phrase "metering and billing" requires clarification. The discussion in D.96-10-074 of the seven issues and four strategies indicates that the CPUC is not limiting its inquiry to narrow definitions of "metering" (i.e., installing, maintaining and reading meters at customer premises) and "billing" (i.e., generating customer bills and sending them to customers). D.96-10-074 clearly recognizes the intermediate data communication and data management steps between metering and billing, in a manner consistent with the discussion of information flows in Section II.D and Table 2 above. The CEC has taken this one step further by recognizing that metering and data communication and management are necessary for more than just the direct access revenue cycle; they are needed for system operations, load forecasting and bidding, marketing, etc. On this basis we urged the CPUC to make metering and billing decisions from a comprehensive understanding of the information flow needs of the entire restructured industry. The comments that follow maintain this comprehensive approach.

1. Meter ownership.

D.96-10-074 uses the phrase "meter ownership" to denote responsibility for maintaining meters and providing accurate meter data, in an industry structure where several parties require data from the same meter. The decision notes that assigning these responsibilities to an exclusive franchise could result in lower unit cost, but could limit customer choice of meter type. It also reiterates the policy, as stated in the December 1995 Preferred Policy Decision [p. 13], that customers will continue to have the right to choose not to obtain a new meter.

The CEC maintains that meter ownership is relatively unimportant, as long as it does not interfere with a customer's ability to switch energy service providers, or prevent multiple utility services (electricity, natural gas, and water supply) from utilizing a common data communication system. The problem of data accuracy should be addressed through standards regarding the performance of the meter and the interface between the meter and the communication system. Once such standards are established and are enforceable, the meter could be owned by the customer, the ESP or another party.

The issue of enforceability of standards is not a trivial one, however. Because the distribution function of the UDC will retain the responsibility to establish, maintain and terminate the physical connections of end-users to the distribution system, it may be appropriate for the same entity to inspect meters for compliance with standards, to detect tampering and malfunctions and to ensure data accuracy.

The CEC opposes continuation of the customer's right not to have an interval meter, as described in the December 1995 Preferred Policy Decision. As the August 30, 1996 DAWG Report reveals, parties have learned a lot about the information flow needs of the industry since that decision was issued. Consistent with the CEC's previous support for universal interval metering, allowing customers to avoid having an interval meter perpetuates existing patterns of energy usage in ignorance of true production costs. One of the great virtues of a competitive power market based upon hourly PX prices — namely, incentives that will increase the efficiency of consumption — will be lost if customers are allowed indefinitely to avoid facing the true cost of their consumption patterns.

2. Multiple provider access to data from a single meter.

D.96-10-074 discusses the problem of using a meter provided by one supplier to measure the service provided by another, possibly competing supplier to the same customer [p. 11]. The Decision expresses concerns with data confidentiality, transactions security and allocation of metering costs among multiple users of the data, and notes that the issues are symmetric regardless of whether the ESP or the UDC controls the meter [p. 14]. We note two more features of the electricity, natural gas and domestic water supply industries: first, the customer consumes the service before the provider knows when or how much the customer uses; and second, the usage meter is on the premises of the customer, remote from the provider.

These concerns support the CEC's earlier assertion that there are some natural monopoly features to information management in the restructured industry (see Section II.D above). In particular, these concerns argue for a central customer usage database that is accessible by all legitimate users of usage data — energy supplier, distribution utility for billing, operation and planning purposes, etc. — and is responsible for ensuring transactions security, customer confidentiality and enforcement of information access protocols. The term "monopoly" should not be construed to mean, necessarily, either of the familiar models of the regulated investor-owned monopoly or the government agency. At least one noteworthy alternative exists in the VISA bank-card model, where the central information entity is owned and operated on a non-profit basis by the competing member banks. The issues raised here by the CPUC provide a strong rationale for looking seriously at this model for the electric industry.

3. Meter Installation.

D.96-10-074 characterizes two options for meter installation: (1) individual installation as a customer chooses to participate in direct access; and (2) system-wide installation under an exclusive franchise. The former is alleged to provide consumers the maximum choice, while the latter enables universal direct access and may offer economies of scale in installation and operation of the metering and data transfer systems [p. 14].

a. Customer Choice.

Allowing customers to choose when to install an advanced metering system (meter, communication link, and connection to a consumption database) does not actually provide the maximum choice for those things of interest to the customer. The meter and its communication system are not final goods, they are merely intermediates that help the customer fit into the new industry structure. A customer's choice not to obtain an advanced metering system actually constrains a customer's energy choices, either in access to various providers or in opportunities to select various energy pricing options. Maximizing consumer choice needs to be viewed from the broad perspective of choosing among energy service options, not from the narrow perspective choosing among metering system options.

Further, failure to select an advanced metering system may mean that the customer is shifting costs to other market participants, because the customer's use of energy at various hours is not being properly metered and charged to that customer. The CPUC's dictum against cost shifting has been skewed in the restructuring debate to mean that subsidies tolerated in the former, bundled rate era should be preserved in the new industry structure. This highly undesirable policy objective will ultimately be unsustainable in the competitive markets of the future. The CPUC has recognized this in the local telephone services industry and is gradually eliminating subsidies. The CEC urges a corresponding set of actions for the electricity industry.

b. Economies of scale in metering and data communications.

The specific cost data needed to assess possible economies of scale in installation and operation of metering and data communication systems are still not available. The August 30, 1996 DAWG Report presented aggregated information from several vendors, who responded to inquiries from the DAWG metering subgroup for vendors to cost out various scenarios of meter and communication system penetration. For competitive reasons, the vendors were unwilling to provide these data individually, and the DAWG Report masked their specific responses to satisfy their concerns.

In its September 30, 1996 Comments on the DAWG Report, ITRON did provide cost data that reveal some sense of the economies of scale for multiple metering and data communication systems operating in parallel with one another. In its Appendix II-C, ITRON suggests that long-term monthly average costs (fixed plus variable) would be 23 percent higher for two systems than one system, and 47 percent higher for three systems than one system. All of these cost increases have to do with the fixed and variable operating costs of the data communication system. For the meters themselves there were no differences in costs.

Unfortunately, no costs have been provided for a least-cost, universal system that can be compared against the costs of the new, ground up systems discussed in the DAWG Report. It may be most cost effective to utilize a multiplicity of existing data communication systems (telephone, TV cable, stand-alone microwave links, etc.), in conjunction with new data communication systems to fill in gaps where necessary, to connect all customers electronically for receipt of PX hourly prices and transmission of usage data for use in load bidding, imbalance detection and settlement, energy usage billing and other purposes. The need to compare this option to others is one reason why the CEC opposes a decision to permit immediate competition for metering and billing services, and supports development of a Retail Information Management Plan (see Section V).

4. Competition in metering and billing.

D.96-1-074 requests parties to identify conditions for open entry and any barriers to entry, to comment on whether significant economies of scope and scale exist between metering and billing, whether contestable markets will drive prices to incremental costs, and if so, whether there is any reason why rates for utility services should not be based on incremental costs [p. 14].

a. Conditions for open entry.

The CEC recommends the following conditions for open entry into any of the metering, data communication, consumption database management, and billing services:

(1) existence of a CPUC approved Retail Information Management Plan;

(2) service offerings compatible with such a Plan;

(3) standards for inter-operability of hardware and software systems, and their information content;

(4) enforceable protocols governing access to customer usage information;

(5) enforceable protocols governing transaction security;

(6) procedures to permit customers to switch easily among ESPs, including requirements for portability of metering equipment contracts; and

(7) the existence of an adequately staffed organization to supervise meter certification and ensure data communication security.

b. Barriers to entry.

The principal barriers to entry are: the current utility monopoly over metering; the absence of standards for inter-operability; statutory restrictions of usage data in Pub. Cal. Util. Code § 588; and the low staffing level of the Department of Weights and Measures to regulate privatized metering activities. The CPUC itself is able to remove the first two, but changes to statutes and the State of California budget will be required to reduce or mitigate the latter two barriers.

c. Significant economies of scope.

As described in Section II.B of these Comments, the revised structure of the industry places tremendous time pressures on ESPs and UDCs to acquire consumption data from customers and use it to refine estimates of loads for the subsequent day's energy market. Thus, economies of scope may exist with respect to metering, data communication (both ways), updating customer usage databases, and system operations activities described above in Table 2. These may be separated from billing and the other revenue handling services described in Table 2, which operate on a longer time cycle.

The time pressures described for metering, data communication and usage database updating do not exist in the traditional utility operations, and can only be accommodated by highly organized, electronically linked data communication and information management systems. At the heart of these time pressures are: [1] the PX and its daily creation of hourly electricity forward prices, with take or pay requirements placed on load bids, and [2] the comparable ISO imbalance identification and settlement procedures that track to specific customers. The proposed California industry structure differs from the UK system, in which a leisurely settlement process dictates the pace of data collection and information flows, because a system-wide access fee covers system imbalances which are never attributed to individual customers.

Under the California system, economies of scope exist for tightly integrated information systems in which price data flow to customers, meter data flow back to providers, and such usage data is used both to settle imbalances and bill for usage and to update prospective load bids that feed into the PX determination of market price. There are ways in which customers can be segregated into parallel pools for which the energy service provider is the integrating entity, but these may not be compatible with the responsibilities the CPUC has assigned to UDCs and the roles permitted of ESPs. A single, centralized entity with control over the full range of information encompassed by Table 2 might be the most efficient approach.

It is important to emphasize that centralized control does not mean ownership or operation of all the elements. Multiple organizations might be involved in acquiring and managing information. The elements to be centralized are: the design of the system to support information flows essential to the industry, and the authority to require system participants to comply with data collection and transfer protocols. It is clear that the UK system failed to properly regulate metering and data communications, and thereby created huge cost recovery and payment problems for suppliers and their customers.

It is highly unlikely that these metering and data communication systems can be contestable once a few of them are in place. They will have high fixed costs and very low variable costs. Much of the fixed costs are associated with the intellectual capital of their system design. Much of their benefits stem from avoiding costs of imbalances due to inaccurate load bids to the PX and schedules with the ISO. An accurate load forecasting capability that is adaptable to evolving customer usage patterns is essential to avoid erroneously high load bids for which payments must be made to the PX, or low load bids which must be covered by imbalance energy in the ISO's reliability operations. It is clear that direct access customers will have such costs internalized within the risks and rewards of the ESP. It remains to be seen how the CPUC will direct UDCs to recover these costs and what incentives will be provided for the UDC to perform as efficiently for their full-service customers as ESPs will do for their direct access customers.

These complexities do not apply to billing and to revenue handling services. Billing and revenue handling are separate activities for which the extreme time pressures and accuracy requirements do not exist. Billing and revenue handling are far more likely to be contestable, especially since these services are already being supplied by some providers of natural gas and telephone services, such as natural gas aggregators and long distance telephone resellers, who will likely extend their retail marketing efforts into electricity services.

d. Pricing at incremental cost.

The previous discussion demonstrates why it would be a mistake for the UDC to be directed to price metering and data communication system services at incremental cost. UDC billing costs, however, may appropriately be priced at incremental cost.

5. Meter Cost.

D.96-10-074 directs parties to provide meter cost estimates, to allocate these costs to generation, transmission and distribution, and to provide a methodology for determining the cost credit that can be given to customers when an ESP provides a service to the customer in lieu of the UDC [pp. 14-16]. This request fails to acknowledge the much more complex issues of integrated information system operations discussed above. Moreover, the direction to allocate meter costs across G, T and D ignores the CPUC's observation that metering has "no unique relationship to any of the three functional areas."

The issues of information flows and system operations cannot be accurately assessed using historic data, since most of the essential activities now under discussion have not previously existed. It is inappropriate to base a credit for private supply of metering and billing services on the UDC customer's bill based on historic costs avoided, since these costs are only weakly related to the cost responsibilities assigned to the UDCs by D.95-12-063. A new formulation of these issues in the context of the four-fold industry structure is required.

6. Bill Consolidation.

D.96-10-074 asks parties to provide comments on bill consolidation and billing cost [p. 16]. The Ratesetting Working Group's December 4, 1996 meeting, at which utilities' December 6, 1996 rate applications were previewed, identified a more fundamental concern: the process of computing costs for energy imbalances, ancillary services and transmission congestion, and the subsequent allocation of these costs to customer bills. The three utilities have proposed different practices with respect to computation and assignment of these costs. It is essential that a common methodology be used to determined these costs, and to assign them to generation, transmission, or distribution portions of a customer's bill.

It appears that the utilities are taking differing approaches based on their interpretations of Pub. Cal. Util. Code §§ 368(a) and (b), created by AB 1890. While the CPUC traditionally allows utilities considerable latitude in developing the functional allocation of cost components within a fixed revenue recovery, in the emerging industry structure it would be intolerable for different utilities to have fundamentally different treatment of the same or similar cost components beginning January 1, 1998. It is also essential that the CPUC determine through its review and approval of the December 6, 1996 rate applications whether distribution tariffs must utilize energy in determining customer specific costs. The necessity of the UDC to have energy consumption data for each and every customer connected to its distribution system has profound implications for the design of metering, customer usage database, and billing practices.

These fundamental issues must be better understood before focusing on the narrow issues of energy bill consolidation and billing cost.

7. Technology development through standards.

D.96-10-074 suggests that technology development will continue, and that an open architecture with standardization of communication protocols is the best method to permit incorporation of evolving technologies and cost/performance improvements. It also suggests that standardization of an on-site bus/network is needed to permit load control at the meter site. A perceived benefit is the increased customer and provider flexibility for direct response to network prices and/or direct load control. Intelligent meters might also allow utility natural gas and domestic water meters to have readings collected remotely [pp. 16-17].

a. Need for standards.

The CEC supports inter-operability of equipment through standards at two interfaces in the metering and data communication systems: (1) between the customer meter and the data communication system, and (2) between the data communication system and the usage database. Placing additional standards and requirements on the communication system in between these two interface points is not necessary and will likely stifle competition.

b. Standards for on-site equipment downstream of the meter.

The CEC opposes standardization of an on-site bus/network. There is no public benefit to be gained from requiring standardization. These should be left to the developers of smart thermostats, appliance manufacturers, and other household goods specialists to resolve.

c. Remote metering of natural gas and water.

The CEC believes that the advantages of remote meter reading for natural gas and domestic water supply are already achievable with today's technology. Several utilities in the United States are deploying natural gas meter reading as part of dual-fuel utility automatic meter reading projects. These projects do not rely upon an intelligent meter. Instead, they typically install an optical sensor on the existing meter (or one precisely like it that has been retrofitted in a shop) which communicates to the data communication network through short distance radio communication links. Thus, the data communication system and its connection to the consumption database are the key elements that permit remote natural gas and domestic water supply meter reading.

Since more than half of California's IOU customers are served by SDG&E and PG&E, it is essential to address the need for these utilities to revise practices of natural gas meter reading. Currently, such meter reading is performed in conjunction with electric meter reading, but this must change to reflect changes in the technology and responsibility for electricity metering and data communication. Otherwise, the cost of natural gas meter reading will escalate as common costs now shared between electricity and natural gas ratepayers will be imposed solely on natural gas ratepayers.

The CEC recommends that the Retail Information Management Plan (discussed in Section V of these Comments) specifically describe how natural gas and domestic water metering can be shifted to electronic technologies and performed in parallel with similar activities for electricity. Unless parties address these natural gas concerns in parallel with electricity, unacceptable cost shifting to natural gas customers will result for customers of SDG&E and PG&E, and cost-saving opportunities for municipal electric, Southern California Gas, and domestic water supply customers will be foregone.

B. Additional Issues the CEC Believes Are Important

The following seven issues are also relevant to decisions to unbundle metering and billing, but do not appear explicitly in the CPUC's list:

1. access of all customers to real time price signals from the PX;

2. data communication systems;
3. mandated meter installation schedules under D.95-12-063;
4. mandated provision of virtual direct access at the customer's discretion;
5. service pricing and cost recovery;
6. data auditing and remittance practices; and
7. statistical sample metering as the basis for load profiling.

Each of these issues is discussed below.

1. Accessibility of all customers to real time price signals from the PX.

It is essential to consider metering and billing in the context of the information requirements necessary to support the whole scope of restructuring now before the CPUC. The CEC continues to support a policy goal of universal interval metering and electronic data communication systems that provide PX price signals to all customers. The CPUC must shift pricing of electric services closer to economically efficient rate designs as quickly as permitted under the constraints of AB 1890. Customers will never respond to electricity production costs if they do not receive price signals that reflect those costs.

2. Data communication systems.

In D.96-10-074 the CPUC has undervalued the importance of electronic data communication systems as a crucial element of the new metering, communication and billing systems that must be put in place to support industry restructuring. In addition to the traditional functions that communication of usage data has supported, three specific new functions must be supported: [1] PX price signaling to users of PX power; [2] rapid usage data uploading to support UDC requirements to procure all energy for its full service customers from the PX; and [3] load forecasting by all scheduling coordinators, including the PX.

Data communication system issues are more complex, and more in need of CPUC attention, than metering itself. For example, it is obvious that virtually no customers have hourly interval metering equipment in place that is suitable for the requirements of the new industry structure. However, large numbers of small customers may already have, installed and in use for other purposes, a suitable data communication link that can provide the necessary electricity data communication services. These may be local entertainment cable, telephone, satellite links, microwave links, etc. Least-cost deployment of needed metering and data communication systems may be achieved by utilizing this existing electronic communication infrastructure, especially as a transitional measure.

3. Mandated meter installation schedules under D.95-12-063.

D.95-12-063 mandated the phased installation of RTP-capable meters and associated communication systems for all customers 100 kW and greater by December 31, 2002. However, D.96-10-074 fails to acknowledge this mandate. The CPUC must clarify whether it wishes to continue to impose this responsibility for metering and data communication systems on the utilities/UDCs as outlined in D.95-12-063, or whether D.96-10-074 rescinds these requirements. The CEC urges the CPUC to rescind the metering mandate of D.95-12-063 pending development of a comprehensive Retail Information Management Plan.

4. Mandated provision of virtual direct access at customer's discretion.

D.96-10-074 fails to consider the impact of virtual direct access (VDA) on utility/UDC metering and data communication systems responsibilities that were created in D.95-12-063. That decision created an entitlement for each customer to have a RTP meter (and presumably, data communication system) installed at the customer's expense to permit the customer to receive hourly PX price signals and to make usage decisions based on these signals. It is crucial to understand, though, that these VDA entitlements place corresponding requirements on the utility/UDC. Utility requirements to provide access to PX pricing and associated hourly billing for hourly usage must be implemented in a manner that recognizes the possibility that large numbers of customers may prefer this option over all others. As D.95-12-063 proclaims, the wonders of the market and the opportunities of customers to respond to it by responding to hourly pricing may be the greatest attraction of restructuring for the residential and small commercial customer. Although the CEC supports universal access to the VDA option, the CPUC should not authorize new rate-based investments by utilities for this purpose before it adopts a comprehensive Retail Information Management Plan.

5. Service pricing and cost recovery.

At this time it is unclear how various energy service providers, including the UDCs themselves, will use hourly loads for pricing their services. Generators will clearly have time-varying generation costs, but this does not guarantee that providers will actually price generation services to their customers on an hourly basis. UDC distribution service may or may not use hourly energy as a variable in tariff formulations. CTC, public benefit program surcharges, and nuclear decommissioning costs could be collected using traditional aggregate measures of generation services usage, which would not require hourly interval data, although hourly interval data could be the basis for such charges.

Emergent ESPs are seeking novel ways to provide direct access to small customers, but AB 1890's requirement to maintain cost components at June 10, 1996 levels to preserve existing rates may constrain their creativity. Since the expressed intent of AB 1890 was to support direct access, if aggregators propose methods where imposition of existing tariffs would increase costs for aggregated customers compared to utility full-service customers, then tariffs ought to be revised to eliminate such cost increases. The CPUC should assess the latitude it has to make appropriate adjustments in cases where aggregated direct access customers are made worse off due to unforeseen tariff anomalies.

6. Data auditing and remittance practices.

Hourly interval data will be utilized to support accuracy audits of metering and remittance practices and load profiling estimation techniques. Audit trails for remittances of funds collected by one service provider on behalf of others are obviously needed to provide confidence that consolidated billing is being performed accurately. Periodic auditing of load profiles may also be needed to ensure that reasonably accurate load profiles are being used. Provisions for such auditing practices must be included in a comprehensive assessment of needs for customer meter data.

7. Statistical sample metering as the basis for load profiling.

Various parties to the restructuring proceedings, and the direct access process in particular, appear to presume that load profiles can be developed that are broadly applicable to large customer classes and fixed through time. SCE and PG&E supported this view in their comments on the August 30, 1996 DAWG Report. The CEC has consistently argued that this approach to load profiling is unacceptable.
As noted in the August 30, 1996 DAWG Report (Section 11.4), and the CEC September 30 Comments on this Report, acceptable load profiling requires four things: (1) definition of customer subgroups that are reasonably homogeneous; (2) statistically valid sampling of customers within each such subgroup; (3) installation of interval meters and data communication systems for the sample customers; and (4) processing of the sample data to estimate the subgroup load profile. Done this way, load profiling is a substitute for universal metering that relies upon continual statistical sampling to accurately represent the subgroup. The mechanics of load profiling will

obviously utilize the very same interval metering and data communication systems addressed in D.96-10-074.

The Office of Ratepayer Advocates and CEC Staff have sought utility assistance to analyze or provide the load research data for determining how much variation exists among residential and small commercial load profiles, and to assess the effects of location, possession of major appliances, and other explanatory factors. This analysis is central to the creation of appropriate subclasses and the identification of samples that are representative of each subclass. Any CPUC decisions regarding load profiling should be based on such an analysis of load research data, rather than upon unsubstantiated assertions that utilities have made in previous filings.

IV. Discussion of Metering Strategies Outlined in D. 96-10-074

The CPUC identified the following four strategies in its decision. The first three are characterized as transitional, while the fourth is characterized as a long term strategy [pp. 17-19].

1. Hourly meters are installed for direct access customers only, without replacement of existing meters.

2. Hourly meters are installed for direct access customers only, and they replace existing meters.

3. New hourly meters replace existing meters on a system-wide basis.
4. Multiple providers have access to data from a single meter, as a result of standardized communication protocols and competition among meter providers.

The CEC asserts that the first three of these strategies are unsatisfactory, even as transitional measures. The fourth "strategy" is actually a desired end result. What is needed is a strategy to achieve this result.

The decision suggests that these four strategies (and any additional ones proposed by Commenters) are to be evaluated in the context of the following objectives: (1) not impeding the prompt availability of direct access to all customers, (2) protecting the integrity of metering and billing, (3) comparable access to the generation market, and (4) no cost shifting.

The CEC recommends that the CPUC revise these evaluation criteria. Section A below discusses the CEC's revised evaluation criteria, and Section B applies these criteria to the four strategies. Section V then recommends a process for developing a comprehensive strategy for metering, data communication, customer usage database management, billing and revenue handling, based on the information flows required to support the restructured industry and using the revised evaluation criteria as goals.

A. Comments On and Suggested Alternative Evaluation Criteria

The CPUC has proposed four criteria for evaluating metering and billing strategies. The CEC proposes that these evaluation criteria be revised in order to fully evaluate the strategies. The discussion below examines the CPUC's criteria and describes the CEC's proposed revisions, which are intended to address the same underlying concerns that appear to have motivated the CPUC's original criteria. Table 3 provides a summary of the original and the revised criteria.

1. No Impediment to Direct Access for All Customers

This criterion frames the metering and billing policy questions narrowly within the context of support for participation in direct access. As argued in Section II of these Comments, metering and billing decisions should be made in the context of the totality of restructuring. Direct access participants are not the only customers for whom revenue cycle services will be different from prior practices. The UDC will be required to perform many different activities on behalf of their full-service customers, to enable them to "fit into" the new structure of the industry. Some of these involve customer information acquired through the metering and data communication systems associated with participation in direct access. Moreover, it is extremely important that the long-term goal of universal interval metering and data communication systems be included in the evaluation of strategies.

The CEC offers the following alternative criterion:

> Support the information requirements of the restructured industry by:
>
> a. contributing to the goal of universal interval metering and electronic data communication systems for all customers within five years;
>
> b. satisfying system operating requirements and revenue handling requirements for all industry participants; and
>
> c. permitting competitive supply where possible as a mechanism for developing a marketing relationship between ESPs and their end-use customers.

2. Protecting Metering and Billing Integrity

There are several issues that are closely related to the integrity criterion proposed by the CPUC. One is the issue of access to customer information that was addressed in the August 30, 1996 DAWG Report. This is a central near-term issue for emergent direct access providers, for it is essential to a level playing field. The CEC supports a reasonable balance between customer privacy and the marketing needs of emergent ESPs, and has made a specific proposal in our November 26, 1996 Comments on the October 30, 1996 DAWG Report. The same issue has a mature-market aspect as well, which needs to be addressed within the comprehensive context of information flows for the restructured industry.

The CEC supports protection of data integrity and transaction security. However, the standards proposed by some parties commenting on the August 30, 1996 DAWG Report may not be sufficient to achieve these objectives. The revenue flows that will be encompassed by electronic communication systems exceed $20 billion per year, which is an enticing target for both unethical parties seeking their own gain and mischievous computer hackers.

It is also essential to support distribution of data to all entities with a legitimate need to know. Thus, if the ESP is permitted to perform revenue cycle services, and the UDC needs customer specific energy consumption data, then the ESP must be required to allow the UDC to have access to that customer specific data. The reverse is equally true.

The CEC proposes the following alternative criterion:

> Support for customer data handling protocols that ensure transaction integrity and resolve access to customer information by balancing customer privacy with marketing needs:
>
> a. customer information access practices that balance protection of customer privacy with the marketing needs of competitive ESPs;
>
> b. ensuring data integrity and transaction security; and
>
> c. access by all legitimate parties to a common energy consumption database.

3. Comparable Access to Generation Services Markets

This criterion can be restated more clearly as support for universal opportunities to participate in direct access or virtual direct access by enabling all customers to readily avail themselves of a full spectrum of energy service options.

The CEC believes that it is crucial to avoid the possibility of customer "lock in" by a single ESP, which customers have complained about in context of today's integrated utilities. Proprietary revenue cycle services have the tendency to require multi-year contracts to amortize their costs. During this period, the customer is contractually obligated to that ESP. A universal revenue cycle services system that can be utilized by all ESPs (including the UDCs) would enhance the ability of customers to switch among suppliers on the basis of the merits of services offered, not on the bundled generation and revenue cycle services imposed by a proprietary relationship.

The CEC offers the following alternative criterion:

> Support for universal opportunities to participate in direct access or virtual direct access:
>
> a. all customers can readily avail themselves of the full spectrum of generation service options; and
>
> b. metering, data communication, and other information services do not constrain customers' ability to shift among energy suppliers.

4. Avoiding Cost Shifting

The CPUC asserts that it is necessary to avoid or prohibit cost shifting. The CEC is concerned that this objective could be used to justify the continuation of existing cross-subsidies. Costs are what they are. The objective should be to collect revenues in such a way that charges reflect true costs, except where explicit policy objectives warrant targeted, transparent subsidies.

The CEC proposes the following alternative criterion:

> Support for efficient pricing of all energy services, supplemented by transparent subsidies where needed to satisfy societal goals:
>
> a. cost responsibility as the basis for revenue collection;
>
> b. clear communication to the customer of the cost of each major component of energy services; and
>
> c. satisfying broadly shared societal goals by transparent, narrowly targeted subsidies to specific customer groups.

5. Summary of Alternative Evaluation Criteria

Table 3 provides a summary of the original evaluation criteria proposed by the CPUC and the alternatives recommended by the CEC.

Table 3. Metering Strategy Evaluation Criteria

CPUC-Proposed Criteria	CEC-Proposed Alternative Criteria

1. No Impediment to Direct Access for All Customerss	1. Support the information requirements of the restructured industry by: a. contributing to the goal of universal interval metering and electronic data communication systems for all customers within five years; b. satisfying system operating requirements and revenue handling requirements for all industry participants; and c. permitting competitive supply where possible as a mechanism for developing a marketing relationship between ESPs and their end-use customers.
2. Protecting Metering and Billing Integrity	2. Support for customer data handling protocols that ensure transaction integrity and resolve access to customer information by balancing customer privacy with marketing needs; a. customer information access practices that balance protection of customer privacy with the marketing needs of competitive ESPs; b. ensuring data integrity and transaction security; and c. access by all legitimate parties to a common energy consumption database.
3. Comparable Access to Generation Services Markets	3. Support for universal opportunities to participate in direct access or virtual direct access: a. all customers can readily avail themselves of the full spectrum of generation service options; and b. metering, data communication, and other information services do not constrain customers' ability to shift among energy suppliers.
4. Avoiding Cost Shifting	4. Support for efficient pricing of all energy services, supplemented by transparent subsidies where needed to satisfy societal goals: a. cost responsibility as the basis for revenue collection; b. clear communication to the customer of the cost of each major component of energy services; and c. satisfying broadly shared societal goals by transparent, narrowly targeted subsidies to specific customer groups.

B. Comments on Metering Strategies

In this section the three near-term strategies and a fourth long-term strategy proposed by the CPUC are assessed using the CEC's alternative evaluation criteria.
These strategies are:

Strategy 1: New Meters Without Replacement for DA Participants, No Other Changes

Strategy 2: New Meters with Replacement for DA Participants Alone

Strategy 3: New Hourly Meters on a System-Wide Basis

Strategy 4: Multiple Providers Obtain Access to Data Collected From a Single Meter

In summary, the CEC does not support any of the three near term strategies, even as transitional measures. The CEC does support the fourth "strategy," but notes that it is a goal in need of an implementation strategy, not a strategy in itself. Section V of these Comments describes a CEC proposal for developing and implementing a Retail Information Management Plan that would address this goal as well as others.

1. Evaluation of Strategy 1: New Meters Without Replacement for DA Participants, No Other Changes

Strategy 1 essentially continues the current utility metering and billing processes and permits ESPs to install duplicative, parallel metering and billing equipment and processes as needed for their own billing purposes. For the larger customers committed to participation in direct access as soon as possible, this is a highly desirable strategy, since the duplicative revenue cycle costs will be trivial in comparison to the energy savings they expect to realize. As a completely privatized revenue cycle service installation, all of the issues of concern to the customer are presumably resolved through voluntary arrangements with the ESP, assuming no meter or communication system upgrades are required for the distribution service.

From the perspective of the CEC's alternative criteria, this is a poor strategy. In fact, it could seriously undermine the CPUC's long-term objective of multi-party access to meter data. Relying on a customized relationship between the customer and the ESP is not consistent with broader goals like universal interval metering and data communication. Customers who choose this route may actively oppose universal interval metering and data communication because of their investment in customized equipment. Strategy 1 will most likely increase the unit cost of metering, which is a trivial concern for larger customers, but for smaller customers would likely tip the break-even point toward remaining a full-service UDC customer. The CEC recognizes the importance of allowing buyers and sellers to enter into customized transactions, but in the electric industry such transactions should be conducted within a common information infrastructure.

2. Evaluation of Strategy 2: New Meters with Replacement for DA Participants Alone

Strategy 2 replaces the existing meter with a new meter and associated data communication systems that support direct access. The description of this strategy does not explain how the data, which must be uploaded to a database, is shared between the ESP, the scheduling coordinator and the UDC.

Strategy 2 does not necessarily require the ESP and UDC to independently access the meter data remotely, as the CPUC suggests. There appear to be no proponents for systems in which the data remains in the meter, which is then interrogated independently by different suppliers. Virtually all hardware and software configurations that allow data sharing do so at the central computer database, usually as a data transfer using a standard telephonic data protocol from one computer to another. The CPUC also appears to assume that each provider will perform its own billing, hence the need for transfers of the data. There are, however, options involving consolidated billing where one supplier never obtains the data for the customer, relying upon auditing to ensure accuracy of remittances.

Strategy 2 is defective on the following grounds:

a. it fails to address the metering and other information needs of electricity consumers that remain full-service customers of the UDC;

b. by focusing on direct access participants alone, it may foster development of fragmented systems that cannot readily integrate into a complete system that supports universal interval metering;

c. by failing to provide for UDC full-service customers, it does not address UDC mandates to support virtual direct access and therefore undercuts the development of a PX market that includes price-responsive load bidding; and

d. it is incomplete as a strategy because it does not address how a single interval meter will support the energy consumption data requirements of both the ESP and the UDC.

3. Evaluation of Strategy 3: New Hourly Meters on a System-Wide Basis

Strategy 3 implicitly requires a comprehensive plan for removal and replacement (or retrofit) of existing meters with interval meters and appropriate data communication systems. Also implicit is a much enlarged consumption database computer system to handle the much larger volumes of data that would flow from these meters.

D.96-10-074 asserts that strategy 3 has nearly the same implications as strategy 2, except potential economies of scope in the provision of meters and data collection network. The CEC disagrees with this assertion. Either strategy 1 or strategy 2 could lead to multiple data communication systems and consumption databases, depending upon what entities were permitted to install and operate the new metering systems described in strategy 2. Strategy 3 is different because a universal metering, data communication and consumption database system requires a central entity. Therefore strategy 3 actually raises quite different organizational and control issues than strategy 2 does.

While strategy 3 could achieve the goal of universal interval metering, which the CEC supports, two issues must be addressed.

One, a more comprehensive treatment of metering, data communication, consumption database management, billing and revenue handling must be performed in order to have a complete strategy. Even if it is viewed apart from these other elements, strategy 3 leaves unaddressed the questions of who would implement it and over what time frame, the recovery of installation and operating costs, and the pricing of services.

Two, a single data communication system may not be the least-cost method of achieving universal interval metering. As described in Section III.A.3 and Section III.B.2 above, data communication systems that rely upon existing communication networks should be investigated. Creation of a stand-alone, single technology data communication system is virtually impossible to achieve given the rural nature of much of California. Accordingly, the CEC supports investigating the possibility of utilizing existing communication systems wherever feasible and cost effective.

4. Evaluation of Strategy 4: Multiple Providers Obtain Access to Data From a Single Meter

D.96-10-074 characterizes this long-term strategy as having two key elements: (1) standardized communications, and (2) competition among meter providers. The CEC strongly supports this goal, but differs with respect to the mechanics of achieving it.

First, there are potential problems with allowing competition among meter providers in the absence of a comprehensive plan. The CEC has supported universal interval metering as a goal to be achieved within a five year time period. Without a master plan to achieve this goal, competitive provision of meters may result in piecemeal deployment, leaving gaps to fill in where the market failed to supply, and precluding some technology options that could have been less costly if implemented systematically. The communication system infrastructure is far more likely to be a source of inflated costs than meters themselves.

Moreover, as the discussion in Section III suggests, standardized communications may not be a good idea. It may be essential to use mixed communication technologies to truly achieve universal interval metering. With standardization at two crucial interfaces -- between the meter and the communication system, and between the communication system and the central database computer -- the routes and physical technologies used for data communication do not need to be the same for all customers. Rural, widely disbursed customers may well use telephone lines, while urban areas may use radio, or entertainment cable fiber or hybrid fiber/coax systems where spare capacity and appropriate cost contracts with cable operators can be arranged.

The long term strategy described by the CPUC requires that consumption data be collected and maintained in a universal consumption database accessible by all energy service providers and certain other parties. A universal database for all customers resolves a number of consumer choice issues. It affords maximum flexibility to change providers, and it ensures continuity of consumption time series for use in load forecasting and load bidding by the ESP. A universal consumer database provides a much more simple means for ESPs to access their customers' usage data than multiple interrogations to retrieve data held within the meter. Multiple ESP interrogations of the meter create greater burdens than standardized data retrieval into a universal database, which would allow each ESP to download its customers' data or use it *in situ* for load forecasting and billing computation.

Finally, as noted above, the CPUC's "long-term strategy" is actually a goal. It is absolutely essential that strategies be developed to achieve this goal. Section V of these Comments proposes a process to develop a Retail Information Management Plan that should serve as a foundation for developing the strategies to achieve this and other goals for the restructured electric industry.

V. Development and Adoption of a Comprehensive Retail Information Management Plan

The CPUC should not make decisions about metering and billing and related services solely in the context of support for direct access, or solely in response to this round of Comments in response to D.96-10-074. A broader framing of metering and data communications topics is needed.

The Joint Assigned Commissioner Ruling (Knight and Neeper; JACR) dated December 9, 1996 directs the utilities, DAWG parties and others to address some of the issues raised in these Comments, for the purpose of assessing the need for a phase-in of direct access. The CEC will actively support that process, and recommends that the CPUC use that process to identify a stakeholder team to draft a comprehensive plan for managing information flows in the restructured electric industry.

A comprehensive Retail Information Management Plan (RIM Plan), developed by stakeholders and adopted by the CPUC, is needed to resolve the numerous implementation and policy issues surrounding retail information-rekated services. As the December 9, 1996 JACR proposes, this Plan must interface with the wholesale information management plans being developed by WEPEX parties, which will be submitted to FERC by the utilities, the ISO and the PX. The RIM Plan should address all consumers -- both direct access and full-service UDC customers. Once such a Plan is adopted, industry participants would undertake activities and roles compatible with it.

A. Development of a Retail Information Management Plan

The RIM Plan should support clear goals and objectives. Since it is intended to be implemented, the Plan must be widely supported and endorsed by the CPUC.

1. Goals the Plan Supports

The goals for the proposed Plan should be the alternative evaluation criteria proposed by the CEC in Section IV.A and summarized in Table 3. Four goals should be:

a. support for the information requirements of the restructured industry;

b. support for customer data handling protocols that ensure transaction integrity and resolve access to information by balancing customer privacy with marketing needs;

c. support for universal opportunities to participate in direct access or virtual direct access; and

d. support for efficient pricing of all energy services, supplemented by transparent subsidies where needed to satisfy societal goals.

2. Scope of the Plan

The RIM Plan should specify the following elements, each of which is expanded in Section B below:

a. a comprehensive description of information flow needs to support the new industry structure;

b. functionality of retail metering, data communication systems and customer consumption databases required to support industry information needs;

c. standards for hardware, software, and information content;

d. activities and roles for industry participants;

e. controlling access to customer information;

f. coordination among utility service providers (electric, natural gas, and domestic water) at a single premise;

g. pricing of services provided by UDCs; and

h. monitoring and oversight of implementation.

3. Stakeholder Development of a Draft RIM Plan

A stakeholder process should be created to prepare and submit a draft Plan to the CPUC, which should then issue a final Plan guiding these activities for all industry participants. The December 9, 1996 JACR directs utilities, WEPEX and DAWG parties to meet to discuss information requirements for the purpose of clarifying whether direct access must be phased in due to technical constraints. This process could form the basis for a stakeholder group that develops a draft RIM Plan. Once the draft is submitted, the CPUC should provide an opportunity for comment and then proceed to adopt a final RIM Plan.

4. Schedule for Developing and Adopting a RIM Plan

As noted above, the December 9, 1996 JACR requires the utilities to meet with WEPEX and DAWG parties. If this group is utilized to designate a team to develop a draft RIM Plan, a draft RIM Plan could be well underway before the end of January. Moreover, most of the knowledge and analysis needed to develop a draft Plan already exists. The RIM team would be able to draw on the DAWG Report and the efforts of various WEPEX teams to develop the comprehensive view of information flows that is required for the RIM Plan. Thus it would be possible to develop and adopt a RIM Plan without delaying the start of direct access. Accordingly, the CEC proposes the following schedule:

January, 1997: Team designated to draft RIM Plan begins work

May, 1997: Draft RIM Plan is submitted to the CPUC

June, 1997: Parties comment on draft Plan

July, 1997: CPUC adopts final RIM Plan

B. The Scope and Issues of the RIM Plan

1. A comprehensive description of information flow needs to support the new industry structure

The Plan must clearly begin with the scope of services it addresses. The performance of these services will require certain information flows among parties. Table 2 outlines an expanded set of information-related services that are appropriate to the industry structure created by the CPUC in D.95-12-063. Four broad categories are described: (1) core activities, (2) system operations activities, (3) revenue cycle activities, and (4) marketing and regulatory activities. The core activities support all the others.

The CEC recommends that the Plan address at least the core and systems operations activities described in Table 2. This, in effect, segregates metering, data communication and consumption database management from revenue cycle, marketing, etc. The former are central to the successful physical operation of the new industry structure, while the latter are important to the commercial success of specific firms in the industry. The Plan should place greater emphasis on the former, and should allow greater flexibility in performing the latter. The Plan ought to concentrate on those activities that contribute to the information infrastructure, which clearly must be controlled or coordinated to a greater degree than other activities for which greater discretion can be granted to ESPs.

Based on the activities identified, the Plan must have a clear description of the information flows needed to support the new industry structure. This was discussed somewhat in the August 30, 1996 DAWG Report (Chapter 3). WEPEX continues to evolve and refine these needs for the bilateral contract form of direct access. There is greater uncertainty in describing how aggregators will collect and utilize information for their direct access customers without interval meters, and who has responsibility for various customer information activities. There is also disagreement and confusion about the information required by the UDC to participate in the PX and to bill its customers for their energy usage.

These and other information flow issues must be identified and resolved prior to making policy decisions about how metering, billing, and other revenue cycle services will be performed under restructuring. Without a clear understanding of information flows required to support various industry activities, the CPUC and parties have no clear, common basis for policy decisions. To proceed quickly with one of the candidate metering strategies under such conditions seems to guarantee trouble downstream when market participants fail to deliver information in the manner and with the timeliness that others expect.

2. Functionality of retail metering, data communication systems and customer consumption databases required to support industry information needs

Given the activities and the required information flows to be supported, the Plan must determine the required functionalities. As one example, the WEPEX ISO Metering and Data Collection Protocol now in development for the WEPEX Phase II filing describes with some care how data for direct access customers with bilateral contracts must be measured and provided to the scheduling coordinator for aggregation with other direct access customers on the same ISO grid out-take node. What is unclear is how load profiling will be accomplished for other direct access participants, how ISO grid out-take metering data can be used as a control total for assigning imbalance energy to aggregated direct access loads and UDC generation service customer loads, and the information flows and data processing steps required to render an accurate bill for those customers without interval metering.

3. Standards for hardware, software, and information content

The Plan should include proposed standards, or standard setting processes, that are needed for hardware, software and information content so that metering, data communication systems and customer usage databases can support multiple technologies, multiple vendors of these technologies, multiple operators of "metering" systems and multiple users of the information.

a. Standards for hardware and software

D.95-12-063 restricts installation and operation of metering by private parties until such standards are established. This restriction should be maintained, but the desire to permit non-UDC installation and operation of metering systems should provide an impetus to develop and adopt such standards.

The August 30, 1996 DAWG report (Chapter 8, Section 8.9) provides a good overview of the standard development process. A few principles should be highlighted:

a. inter-operability of metering equipment from multiple vendors;

b. adaptability of the meter to communication system interface with minimal cost; and

c. data integrity and transaction security should be maintained at all times and against substantial threats.

b. Standards for information content

Parties have not previously discussed standards for the information content to be required of metering, data communication systems or customer consumption databases, yet these are important to the operation of the restructured industry. The following information content requirements are proposed for further discussion:

a. each day, hourly market clearing PX prices for the 24 hours of the following day should be communicated to each customer in a standardized format capable of triggering automatic control equipment, if installed;

b. communication system should be capable of routing ISO load drop signals to specific customers in a standardized format capable of triggering automatic control equipment, if installed;

c. on a daily basis, 24 hourly energy consumption measurements with a time channel synchronized to a master clock to permit merging with PX hourly prices should be uploaded to the entity responsible for maintenance of the customer consumption database;

d. daily uploadings of 24 hourly consumption meter readings should be added to the master customer consumption database when the data passes appropriate verification checks (completeness, range checks, and plausibility);

e. customer consumption database should be capable of storing at least 13 months of hourly meter readings to support periodic load bidding;

f. each supplier of services to a customer may access customer consumption database, for their own customers only, through on-line, real time queries or through downloading of customer-specific consumption data extracts at the ESP's option; and

g. customer consumption database should be capable of switching their supplier with a simple ESP ID change in the database so as to enable customer choice of supplier without sacrificing data integrity or customer-specific consumption time series.

4. Roles of industry participants

Current CPUC requirements, largely specified in D.95-12-063, restrict official metering and other revenue cycle services to UDCs. Nothing prevents ESPs from offering duplicative services as long as these are not substituted for the official revenue cycle services. Therefore ESPs can provide sub-meters (or can tap the official revenue meter) and data communication systems for their direct access customers. This is already happening in the well known case of Federated Department Stores and Southern Energy International (SEI). SEI meters electrical usage at all Federated Department stores throughout the United States, transmits data to Atlanta, routes usage reports back to stores over the Internet each night, and provides billing services for Federated for every one of the utility service areas in which a Federated Department store is located. As a large commercial customer within the utility service area, Federated can apparently tolerate the duplicative metering costs charged to it by utilities and SEI without any direct access energy savings. Many other large customers will presumably also obtain net benefits once direct access is permitted. What is also clear, however, is that below some minimum load size, the overhead of duplicative metering and billing will prevent the customer from obtaining net benefits.

These existing non-utility sub-metering arrangements encourage emergent ESPs like SEI and their customers to believe that they can readily provide the services that utilities have traditionally provided. What needs to be discussed is the degree to which the ESP can provide the information services that will be required for the new industry structure. The complexity of metering, data communication and consumption usage database services is expanding dramatically, and timely access to core services to support new activities will be important operationally and financially.

The policy issues for the CPUC to resolve concerning participants' roles include:

a. how can the overhead costs of duplicative core data collection services be reduced?

b. do the metering and data communication choices permitted of the early participants in direct access preclude cost-effective technologies or organizational solutions that are only cost-effective if performed universally?

c. will the duplicative metering and data communication choices of ESPs lock customers into a particular ESP and reduce consumer choice opportunities?

d. are there technologies and organizational solutions that the UDC would select as the default supplier that would not readily permit its full-service customers to participate in direct access at a later time?

e. if duplicative services are to be avoided, which entity performs them and what cooperation is required among entities?

The parties to this proceeding tend to split in supporting either UDC or ESP provision of the core data management and revenue cycle services. The CEC believes that there are alternatives worthy of consideration. In the August 30, 1996 DAWG report (Chapter 8, Section 8.7), and in the CEC's September 30, 1996 Comments, we urged consideration of a central entity to perform core data management activities. There are at least three variants of this concept: (1) a regulated, private monopoly, (2) a government agency, and (3) a stakeholder-owned non-profit corporation.

The CEC believes this concept has merit. The central entity would have unique authority to obtain meter data for all customers regardless of service provider, would maintain a database of customer usage data, would distribute specific packages of information in a timely fashion in accordance with established protocols, would enable access to certain kinds of information by authorized parties, and would maintain the security of the information management system.

The Plan needs to determine which entities will be assigned responsibilities for or permitted to supply core, system operations, revenue handling and other information-related services. It must also determine the roles parties will play in implementing needed new hardware and software.

5. Controlling access to customer information

The Plan should address how the principles governing access to existing and future customer information will balance protection of customer privacy with legitimate needs for information for preparing bills for services or for efficient development of markets.

a. Access to existing, utility-held customer information

The August 30, 1996 DAWG report (Chapter 7) provides a comprehensive overview of the issues which must be resolved with respect to accessing existing utility-held customer consumption data. The CEC's November 26, 1996 Comments on the DAWG Consumer Protection and Education Report describe a specific proposal for balancing customer privacy with the marketing needs of new providers. However the CPUC decides to allow access, the RIM Plan should provide for the implementation activities required to put the CPUC's policy decision into effect.

b. Access to future customer information

Once the new industry structure begins operation, customer information will be different and will be handled by different parties. These changes will require adaptation of the rules of access for existing customer information to suit the new circumstances.

First, energy consumption data of many customers will be hourly rather than monthly, and the supplier of generation services will be specific to each customer. If customers are concerned about privacy for monthly consumption data, they will likely be more concerned about hourly consumption data. Hourly readings indicate patterns of premise occupancy, which pose greater threats to personal and property security than any other data available about premises. Unauthorized release or use of hourly consumption data should be proscribed and severely punished. Stringent rules and effective enforcement will be needed to assure consumers that their privacy is being protected.

Second, the existence of many new market participants means that customer information will be of substantial importance to the success of ESPs. Customer lists (with or without indicators of transactions types and volume) are commonly sold by businesses for commercial purposes. The CEC supports some degree of continuing access to customer usage databases for marketing purposes because such access will facilitate efficient markets for energy services. The Plan should offer a proposal regarding such use, but ultimately the CPUC will need to establish the degree to which commercial use of customer consumption data is permissible. Cal. Pub. Util. Code § 588, which restricts access to customer energy consumption data, must be reviewed and perhaps amended through the legislative process.

6. Coordination among utility service providers (electric, natural gas, and domestic water) at a single customer premise

The Plan should address how the information services aspects of all utility services (electricity, natural gas and domestic water supply) provided to a single premise can be better coordinated. As the CEC has noted previously, and as D.96-10-074 acknowledges, the possibilities of multiple utility services using electronic data communication systems for transmitting metered usage data from customer premises to the energy service provider's billing system are quite exciting. The customer may be able to achieve benefits by reducing what have traditionally been completely separate data handling activities by each of the separate utility service providers.

SDG&E and PG&E have combined meter reading systems, which reflects the fact that their customers have a single supplier of two utility services. Revising the electricity industry's metering, data communication and billing systems must take into account that these two utilities have closely interacting electricity and natural gas systems. If the CPUC permits electric metering systems to be provided competitively, it must make arrangements for natural gas meter reading and billing to ensure that costs do not increase for gas customers. The Plan should address how this would be accomplished.

7. Pricing of services provided by UDCs

The details of regulated pricing of utility services is beyond the scope of this Plan, but it is essential that the process of developing the Plan address how and where pricing of services will be resolved. No other parties can readily evaluate their own options without some understanding of the manner in which they will "compete" with the UDC. The threshold question, of course, is which of the various customer information services will be restricted to the UDC, which can be offered by both the UDC and other providers, and which can only be provided by private firms. In telephone deregulation, the CPUC refers to these as monopoly, semi-competitive, and competitive services.

a. Monopoly and competitive services

To the extent that some information services are restricted solely to the UDC, or perhaps to some other regulated monopoly, the details of pricing these services would not be of special concern to private firms since no competition is permitted. Correspondingly, if some services are provided solely by competitive firms, then monopolies would not supply them and no price regulation would be required.

b. Semi-Competitive Services

It should be understood that if the UDC is providing services in competition with ESPs or even third party providers, the UDC's pricing of the services must be well regulated. The UDC should be provided flexibility to adjust its prices to meet competition, yet must not be permitted to shift costs for competitive services to monopoly services. The CPUC has created just this environment in its local telephone services unbundling decisions by recognizing competitive, semi-competitive, and monopoly services. Once established, semi-competitive services are allowed pricing flexibility within floors and ceilings with no advance notification or approval by the CPUC.

The key to accomplishing these results is a PBR incentive environment customized to address unbundling of services and explicit recognition of semi-competitive services.

Unfortunately, neither SDG&E nor SCE have appropriate PBR mechanisms to address these concerns, and PG&E has no PBR affecting distribution or customer services at all. The CPUC needs to determine whether special stand-alone, PBR-like incentives should be created to address unbundling of revenue cycle services, or whether this incentive should be created in the broader context of comprehensive distribution and customer service PBR packages. The CPUC must also address the degree to which AB 1890 constrains such innovative rates during the period of the freeze.

8. Monitoring and oversight of implementation

The Plan should describe how its goals will be achieved. This suggests a need for a monitoring and oversight process that includes exercises of judgment about the pace of progress. In addition, in order to be responsive to changing regulatory or technological circumstances, the Plan ought to have some degree of built-in flexibility.

Some portions of this oversight must be the responsibility of the CPUC, while others might be placed in a industry-wide stakeholder organization. If standards cannot be established and adopted during the preparation of the Plan, then a standard setting process must be enabled by the Plan, which would require a stakeholder group to be enfranchised to develop a proposed set of standards.

A matter requiring some delicacy is the need to keep the municipal utilities, for which the CPUC has no direct oversight authority, fully involved in the implementation process as well as the development process. A broad stakeholder implementation entity might have some success in keeping implementation activities that should be coordinated with municipal utility information service activities on track.

C. Permitting Competitive Supply of Customer Services Compatible with the Plan

Once a draft Plan has been submitted and a final Plan adopted by the CPUC, it would provide the basis for determining which activities must be or may be provided by non-UDC parties. As discussed above, the CEC believes that fewer opportunities exist in very short run for core services such as metering, data communications and consumption database management than for revenue cycle services such as billing and revenue handling. It is clearly essential for ESPs to perform load forecasting and other system operation services on the basis of the data collected from customers, even if the UDC or other monopoly entities are the ones which undertake the acquisition of the data. Therefore, access to customer usage data in a timely manner is crucial irrespective of whether one or more organizations are involved in providing these services to or on behalf of customers. Delays between administrative units of a single organization are just as intolerable as are delays between independent organizations.

The Plan should describe when and how ESPs and third party service providers may enter the market for various information services. There are at least three different approaches that could be used, and each may be applicable to a specific activity or service. These are:

a. date certain - a specific date determines when service providers are able to offer specified services to one or more classes of customers;

b. condition certain - a well identified, unambiguous set of conditions describes when service providers are able to offer specified services to one or more classes of customers;

c. requirements certain - a specific set of requirements, and their certification for a specific service provider, determines when that provider is able to offer specific services to one or more classes of customers.

As a general observation, since various functional capabilities require interaction with other providers, the CEC supports condition and requirements certainty rather than date certainty. This places the responsibility on service providers to establish that they have the capabilities needed to do a specific task, and avoids arbitrary dates and possibly arbitrary conditions that are irrelevant to ensuring that a quality job will be performed.

Date: December 19, 1996 Respectfully submitted,

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